BUREAU OF LAND MANAGEMENT

TRIBAL FORUM ON ONSHORE

ORDERS 3, 4 & 5

Tuesday, December 1, 2015

Morning Session 9:00 a.m. - 12:00 p.m.

DoubleTree by Hilton
501 Camino Del Rio
Held in Ballroom
Durango, Colorado 81301

I N D E X

AGENDA

P R O C E E D I N G S

THE FACILITATOR: I would like to introduce first Terry Knight, I guess, who is the tribal -- this is a long title here, Terry -- the tribal historic preservation officer for the Ute Mountain Ute Tribe. Terry is going to do the invocation for us.

(Invocation is given by Terry Knight.)

THE FACILITATOR: Terry describes himself as spiritual technician, so thank you.

I'd like to introduce Lonny Bagley now, who is the deputy state director of the BLM.

MR. BAGLEY: Good morning, everybody, and welcome to Durango. As Liz pointed out, I'm the deputy state director for energy, lands, and minerals for the State of Colorado here, stationed in Lakewood, Colorado.

Today here with me, I want to introduce some folks that are also here outside the speakers: We have Connie Clemmentson, who is our field manager.

UNIDENTIFIED SPEAKER: Good morning.

MR. BAGLEY: Matt Azhocar. He's the acting district manager. Justin Abernathy is our assistant field manager here. John Pecor is a petroleum engineer, and a lot of Tribal folks have probably worked with John before, and Sue Mehlhoff is my branch chief back in Lakewood, and we have Mr. Fuge, Dylan Fuge, out of the Washington office. Dylan is our senior advisor to the director; is that correct, Dylan?

MR. FUGE: Yes, sir.

MR. BAGLEY: I'm glad you all could make it here. Anybody that I missed? All right.

Well, we're here to talk about the new onshores that are coming on -- Onshores 3, 4, and 5, which we have here on the screen. Onshore 3 deals with site and security. 4 is oil measurement, and 5 is gas measurement, and we have our subject matter experts here today to talk about that.

The Rules are out right now and have been out for quite a while. The public comment period is going to end on December 14th for the public.

In relationship to Tribes, we'll accept comments from Tribes all the way up until the Rule is published. So Tribes have a little bit longer period of time to work within our system and work with us on how the Rules are going to be finally implemented. So we're going to enjoy that participation.

For the folks here from Tribes -- are there folks here that represent Tribes from a consultation standpoint?

UNIDENTIFIED SPEAKER: What standpoint?

MR. BAGLEY: Government-to-Government consultation. For those individuals, we -- I'm sorry. You're also here for the Tribe?

UNIDENTIFIED SPEAKER: Yeah.

MR. BAGLEY: Any here from the Tribes? Okay. All of you are represented for consultation. Okay.

That's very important for this meeting for a Tribal aspect of it. We want to have your input into this process, and it's very important to the Bureau of Land Management.

And one of the things I'd like to invite right now is, if any of the Tribes would like to have a one-on-one consultation with their councils here in Colorado, we can set that up to where we can do that after this meeting and have more of a formal consultation or government-to-government, one-on-one meeting with the Tribes. If you'd like that to occur, then please see me and we can set those dates up.

All right. Moving on, today the purpose again is to get your input into the Rule. We have a court reporter here to provide a record for this meeting and provide that as far as an administrative record for the Rule.

Our format is going to be, we're going to have our senior staff members that worked on the Rules or are leads on the Rules, and they are Mr. Rich Estabrook, is first over here as Onshore No. 5 lead, Mike McLaren, who is the Onshore 4 lead, and Mike Wade, who is the lead for site and security.

So they're both going to be giving -- or all three will give presentations today, and at the end of those presentations, we'll offer up a question-and-answer period. We didn't want to get too far into the other Rules without stopping and getting some input.

So from that, I'm going to turn it over to Mr. Mike Nedd, who is our assistant director for energy or lands and minerals out of our Washington office. He's going to open that up with a few remarks. And so, Mike, I'll turn it over to you.

MR. MICHAEL NEDD: Thank you, Lonny. And good morning to everyone. It's certainly good to see your faces out here. As I said when I flew in last night, it seems to be warmer here than it was in Texas where I came from because of all the rain and the cold, but it's good to be back here. I was here a few months ago.

As Lonny said, I'm Mike Nedd from Washington, DC, and I get to play a part in setting the Rules and the operational aspects for the BLM when it comes to oil and gas and minerals management.

We're glad that each of you are here today. We began this discussion, this Tribal discussion, a few years ago, and so today is very important to continue that dialog.

We value your input, and we realize that we cannot put out any rules or regulations without first hearing from you and getting your input because at the end of the day, where it matters is how it's implemented on the ground and how it affects the work and your Nations and your individuals.

And so we want to continue that dialog today.

As Lonny said, you can provide comments throughout the entire process until we publish that Rule, and so that opportunity to give comment, whether it's now, or whether it's on a one-on-one, or certainly by mail, hard mail or e-mail, you can continue to provide that.

We realize and know that energy development is very important to the Tribal Nations. And so BLM, in its trust responsibility, wants to ensure that everything that should be going to those Tribes are accounted for and properly done in such a manner. And so we want to make certain that has happened.

As we move forward in this dialog here, we will be moving on to Oklahoma City. We also will be in North Dakota but, again, the discussion will continue. And so again, thank you today for being here, and I wanted to say -- I overlooked to say, you know, we know there have been a number of GAO audits that came out and said we need to do a better job about these regulations on our onshore orders.

So part of these updates to these regulations will help to satisfy that. And so, again, this has been an effort of many years, and these gentlemen here have been doing this for quite a number of years and so trying to get to the end is very important.

So, again, thank you for being here. I know there are a number of you that said you are representing the Tribe, and we would prefer for you to be up front, but you can certainly sit wherever you so desire and, again, looking forward to the discussion. So with that, I will turn it over to Richard Estabrook.

MR. ESTABROOK: Thank you, Mike. Again, my name is Rich Estabrook. I am a petroleum engineer. I actually work for Mike Nedd's staff out of Washington, DC. I actually live on the north coast of California, which is a really sweet deal.

So I'm going to kick this PowerPoint off a little bit, and then we're going to go through Orders 3, 4, and 5 consecutively. So, again, the outline for this session, our part of the outline here is, I'm going to talk briefly about why these regulations are important.

I'm then going to go into why we are revising the existing onshore orders. Then I'm going to go through changes proposed for all three orders, changes common to all three orders, and that includes a new Subpart 3170 in the Federal regulations.

I will then turn it over to Mike Wade, and he will go over the details of proposed changes to Onshore Order 3, which will now be called Subpart 3173. After Mike is done with his presentation, we'll pause for your input, questions, and comments from you. I'll then turn it over to Mike McLaren, and he'll talk about proposed revisions to the

Onshore Order 4, which is oil measurement, and that would be in a new Subpart 3174.

After he's done with that presentation, we'll again pause for your input and questions and clarification and comments, whatever you have, and I will wrap it up going back to proposed revisions to Onshore Order 5, which is gas measurement, and a new Subpart 3175. And when I'm done, we'll open it up again for questions and comments specific to Onshore Order 5.

So why are these regulations important? And there's one really simple answer. They're important because of money, of royalty dollars. That's why these are important.

I just wanted to go over quickly how royalties -- this applies to Tribal and Federal royalty -- basically the exact same equation. I'm going to go through how oil royalty is calculated and returned to the Tribes.

Royalty is equal to the royalty rate on the lease times the volume in barrels of oil removed from that lease in a given month times the value of that oil in dollars per barrel.

Going in, contributing to the value of that oil is the quality of the oil in API gravity. It's not a direct multiplier, but it certainly goes into the valuation of that oil.

The royalty rate is set in the lease term. It's generally a fixed number. It doesn't change. It's not something that the onshore orders are concerned with, but it does enter directly into the royalty calculation.

The value of the oil, the dollars per barrel, is not our responsibility. That actually is determined by the Office of Natural Resources Revenue. It's nothing to do with BLM. It's a different agency under the Department of the Interior.

Onshore Order 4 and a little bit of Onshore Order 3 that we'll be talking about in detail here in a little bit directly affect the volume of oil reported on which royalty is due, so the reason Onshore Order 4 and 3 are important is because the provisions of these onshore orders directly affect how accurately the volume is measured and how properly it is reported.

Also, Onshore Order 4 talks about API gravity. Part of Onshore Order 4 is how to accurately determine what the gravity of that oil is. And, again, that does not go directly into the calculation of royalty, but it does indirectly affect it because it affects the value of that oil.

Gas is very similar. Royalty on gas is the royalty rate on the lease times the volume in thousands of cubic feet or Mcf of gas removed from that lease during any given month times the heating value of that gas times the dollar value of that gas.

And just like with oil, royalty rate for gas is set in the lease terms. It's not something that we deal with on a day-to-day basis.

The value of the gas is determined by the Office of Natural Resources Revenue, which is not BLM's responsibility. Order 5, however, and a little bit of Order 3 do talk to great lengths about the volume of oil or volume of gas that's removed from a lease in a given month.

So the provisions of Onshore Order 5 and a little bit of Onshore 3 directly affect how accurately that gas is measured and how properly it is reported, which directly affects royalties going to the Tribes.

Order 5 also talks about the heating value of the gas. One thing I want to point out here is that with the gas side of things, volume and heating value each affect royalty the same.

So, for example, if an operator was to report volume 10 percent in error, the royalty from that lease would be 10 percent in error. If an operator was to report the heating value 10 percent in error, you would have the same net effect on royalty. So heating value and volume are equally important in the calculation of royalty that comes back to the Tribes.

Just some statistics here -- this is a ten-year history of oil production from Tribal leases. You can see that starting in 2004 all the way through about 2010, oil production was pretty consistent, around 10 million barrels per year.

Starting in 2010 and continuing today, there's been a tremendous increase in the production of oil from Tribal leases. And this is due primarily to increased production from the Bakken area in North Dakota.

So royalty is based for oil on volume and the price of the oil primarily. The price of -- crude oil price, as shown by the green line here -- and you can see that in 2004, oil was running about 35 dollars per barrel. We had a huge peak up to over 90 dollars a barrel in 2008, dropping back down, and now it's sort of stabilized around 80, 90 dollars per barrel.

Now, this is 2014. We all know that in 2015, we've had a tremendous decline in the value of the oil. We don't have the 2015 statistics up here yet.

So if you combine production and value together, you get the royalty that goes back to the Tribes, and that is shown by this magenta line, and the scale for the magenta line is actually over here on the right side of the graph.

From 2004 through about 2010, the Tribes were receiving about 100 million dollars per year in royalties. With the new Bakken development, the amount of royalty coming back to the Tribes has increased substantially. Now in 2014, it was about 850 million dollars that came back to the Tribes.

Again, the provisions of Onshore Order 4 or the proposed provisions of Onshore Order 4 have a direct effect on this bottom line, the royalty that comes back.

For gas, gas production looks a little different than the oil, but in 2004, gas production was about 300 million Mcf per year, and we have had basically a steady decline. Right now in 2014, it was about 240 million Mcf from Tribal leases.

Gas prices have been kind of erratic over this time. In 2004, we were -- the scale for the gas prices over here on the right-hand side -- sorry for the confusion. But in 2014, the gas price was about $4.50 per MMBtu. That's millions of Btu's. In 2008, we had a tremendous spike. It went up over $8 per MMBtu, and now it settled down around 4, and again, in 2015, gas prices have also dropped along with the oil. It's not reflected in this graph.

We don't have the 2015 statistics yet. I believe wellhead prices are now running around $2.50 to 3 dollars, in that range. If you combine MMBTu's, the production, and the gas price together, you get royalties, which is the magenta line.

And from gas royalties, we're back over to this side of the graph here (indicating). In 2004, gas royalties going back to Tribes was about 200 million dollars. It peaked here in 2006 actually at about 350 million, and in 2014, it was about $180 million.

So why are we revising these regulations? And before I get into why, let me just explain what exactly we're proposing to do. So right now, we have Onshore Orders 3, 4, and 5. Onshore Orders are a very odd entity in the Federal Government. I think it's the only uncodified regulation. They have the weight of regulation, but they were never published in the 43 CFR, so you can't find them there. These are oddball regulations.

What we're proposing to do is create a new regulatory subpart under 43 CFR, Part 3170, that would cover everything related to measurement and production. In the Part 3170, there would be a number of definitions that would be common to all three proposed regulations.

There would be recordkeeping requirements that I'll go over in a little bit. There will be a statement about bypass and tampering. We're going to talk about variances, appeals, and enforcement. So all these things would be in the main subpart of 3170.

Under 3170, we are proposing three subparts: First, Subpart 3173, which would replace Onshore Order 3, and this would deal with site security, FMP, which means facility measurement point, commingling, and off-lease measurement. And Mike Wade will be going into that in much more detail when I'm done with the opening session here.

Subpart 3174 would replace Onshore Order 4 and deals specifically with oil measurement, and Mike McLaren will go into more detail about those proposed changes.

Subpart 3175 would replace Onshore Order 5 and the State-wide Notices to Lessees for electronic flow computers. Right now, each jurisdictional state in BLM has a notice to lessees for electronic flow computers, and those would all be replaced under this proposal, and they all deal with gas measurement.

So why revise these Orders? First of all, Onshore Orders 3, 4, and 5 came out in 1989. That's 26 years ago. They are very old. The current orders do not address new technology or incorporate the latest industry standards and practices.

For example, for oil measurement, Coriolis meters are becoming very common and generally accepted by the industry. Because our Onshore Order 4 is so old, Coriolis meters -- I don't know -- if they existed back then, they weren't used for oil measurement. There's gaps in the existing orders that need to be addressed.

For example, Onshore Order 5 has one and only one requirement that deals with the heating value. Now, remember, my equation was that both volume and heating value equally affect the royalty due. Onshore Order 5 has a lot of stuff.

It's old, but a lot of stuff on volume, but has one and only one requirement for heating value, and that is you have to determine it once a year.

There is nothing in Onshore Order 5 about how you determine heating value, where you measure it, how you measure it, how you analyze it, or how you report it. It's a huge gap that we intend to respond to in this proposal.

We also need to respond to a number of reports and audits. As you probably know, our Agency gets routinely audited by several government entities, such as the Government Accountability Office, the GAO.

There was a 2010 report that had numerous recommendations about how we need to improve production accounting, accurate measurement, and reporting. The Office of Inspector General has issued numerous reports about the same thing.

And in 2007, the RPC, which is the Royalty Policy Committee -- it was under the old Mineral Management Service. And they came out with a report that had 110 recommendations for Department of Interior as a whole, not just BLM -- 110 recommendations of things that the Department needed to do to improve our production, accounting, and handling of royalty-bearing volumes and qualities of oil and gas.

Of those 110 recommendations, 12 of them were specifically about measurement issues, volume, and quality.

So these proposals that we're going to discuss today will respond to those recommendations, will also respond to GAO and OIG recommendations and shortcomings that they found.

In general, why revise these Orders? Because we need to improve measurement accuracy, reporting, and accountability. We don't feel the existing orders are doing that well.

So I'm going to talk about now -- I'm going to get into some specifics, general things that we're proposing to change with these new regulations.

First of all, if you're familiar with the onshore orders -- how many in here are actually familiar with our onshore orders as they exist now? Okay.

(Show of hands)

MR. ESTABROOK: Now, currently for each provision in the onshore orders, the operator must calibrate the gas meter quarterly. That's the requirement, and for each requirement, there's a corrective action which includes if you don't calibrate that gas meter quarterly, for example, it's going to be either a major or minor violation, and that's specified for each provision.

There's going to be a time frame of what to do and a corrective action of what you have to do to fix that violation.

What we're proposing with these new regulations is that we would take those enforcement actions out of the regulations or the onshore orders and stick them into a manual.

The reason we want to do this is because those enforcement actions that are currently in the onshore orders have been widely misinterpreted by both industry and the BLM. They are routinely interpreted as gospel truth set in stone.

So if the violation says this is a major violation, then it's a major violation no matter what. The time frame is 30 days, and it's 30 days no matter what. And those enforcement actions in the original order were never intended to be set in stone. They were intended as a guidance as to how our inspectors were to interpret the violation.

The bottom line is substantial adverse effect of an impact. If it says it's substantial and adverse impact, then it's a major violation. So some things may generally be a major violation, but there's always extenuating circumstances that may not always be a major violation.

For example, if you found something on a very low-producing well, a low-producing meter, even though the onshore order says it's a major violation because it produces such low quantities, it may not be.

So by taking these enforcement actions out of the regulation itself and putting them into a manual, we think we can address these in a much more consistent way.

Current onshore orders have one and only one immediate assessment, and that has to do with Federal seals. The proposed regulations would include numerous immediate assessments added to each subpart, and they would be to compensate the BLM for what's called liquidated damages, which is a legal term that I don't want to get into because I don't understand it that well, but it would be a flat $1,000 per violation.

Right now in the onshore orders, each Order has a section on variances, and the technical review of alternate measurement devices or alternate measurement techniques are currently left up to the individual field offices. This is an issue for industry, I know, because of the lack of consistency.

We have had cases, for example, in Wyoming where an operator in one field office wanted to use a different type of gas measurement device. One field office said, "Fine." Another field office said, "Fine, but with this condition," and another field office said, "Forget it. You're not going to do it at all."

So what we're going to propose is a new production measurement team would be establishing reporting, and they would do all the meter device approvals on a national level. The team would specialize in this. They would be very skilled in this, and they would be able to provide consistent and good reviews and consistent conditions under which that meter could be used.

Getting to Part 3170, again, this is the blanket regulation that will cover all three subparts. Currently, the requirements in the onshore orders only apply to operators. They don't apply to purchasers or transporters -- only operators.

What we're proposing is that recordkeeping requirements, only recordkeeping requirements, would now apply to purchasers and transporters through the royalty settlement point or the point of first sale, whichever comes first.

So this has been an issue again with a lot of operators. We will do an audit request. We want all your config laws and volume statements from a gas meter from an operator, but the operator doesn't own the gas meter. A pipeline owns the gas meter.

So the operator goes to the pipeline and says, "BLM is doing an audit. Can you please send us all the stuff that they want because it's your meter."

And the pipeline company may say, "Oh, you know, we don't want to for whatever reason. We're not going to provide you that information. We can't find it" -- whatever their reason is.

We would then take enforcement action because you did not comply with our written order for that information.

And right now, our only choice is to take that enforcement action against the operator even though it's not even your meter. So we now would propose that we can go to the purchaser and transporter if they owned that meter directly and ask for that information, and if they did not comply, we could take enforcement actions against that purchaser or transporter.

This is actually a latent authority we have had through the Federal Gas and Oil Federal Royalty Act. We have never implemented until -- we would implement it under this proposal.

Right now, we have various definitions that are given in each onshore order. Part 3170 and the proposed 3170 would include definitions common to more than one subpart. Also, there's a variance section specific to each order, and all that variance language would be put also in the proposed Part 3170.

The variance language would also change a little bit and make it more specific about what kind of information we would need to grant a variance and what the goals of the granting of the variance would be.

So I think with that, I will turn it over to Mike Wade, and he will discuss the details of proposed changes to 3173.

MR. WADE: Thank you, Rich. My name is Mike Wade.

I represent the Washington office, although I physically sit in the Denver office, the Colorado State office. I got that additional benefit. And I am a petroleum engineering technician by training and trade since 1983.

With the proposed revisions, the current orders contain variance sections -- wait a minute.

(Mr. Wade is given instruction regarding the Power Point.)

MR. WADE: Okay. That's the problem. There's currently no guidance in the current order for commingling or off-lease measurement. What we were proposing for Order 3 is to provide some specific procedures and guidance on what to submit when proposing and requesting off-lease measurement or commingling, as well as how the Bureau would be looking at processing that.

The Bureau would primarily be looking at impacts to royalty where there was no impact to royalty measurement. That's a very easy one to approve for commingling. This would be, for example, the same royalty rate on all the leases that are being combined and ownership all the same.

So that $10 from one lease, plus $10 from the other lease will still be $20 even commingled. No impact for anyone on those.

We would have some room for variances for things like extreme low volume production and other extenuating circumstances or concerns in order to achieve ultimate recovery -- maximum ultimate recovery.

Part of this process would involve the BLM reviewing existing commingling and off-lease measurement approvals when the operators request approvals for an FMP, Facility Measurement Point.

And those existing off-lease measurement approvals that do not meet the requirements in the proposed new regs which will then be the final regs will be rescinded or modified, working with the operators and all other concerned parties at first in an attempt to get those into compliance before they were rescinded.

On proposed, right now, Order 3 applies to all sales and allocation meters and measurement related to royalty payment is not consistently defined or tracked. The proposed Rule would apply to measurement affecting royalty, and the BLM would approve and track facility measurement points, FMPs. Operators would be required to obtain that number from us.

Currently, for Order 3, run tickets contain some limited value of information and some things that are not specifically covered, except for some real basic, generalized information as you can see for water draining and hot oiling.

We are proposing to add a few additional requirements for water draining, hot oiling, et cetera. Primarily, these are related to a little more detail with the seal records for who removed it, why it was removed, seal numbers, et cetera. Run tickets will now be moved to 3174 instead of 3173 for the detail as to what information is required on those run tickets.

End-of-month inventories are currently not required or beginning-of-month inventories are not required, either. The proposed order would require an end-of-month inventory being measured and maintained by the operators. This only pertains, of course, to oil measurement, not to gas.

No information related to royalty-free use or used on lease. Some people call it beneficial use. It's all changeable. It's currently in Order 3. We are proposing to require the operators when they submit their facility diagrams, if they are going to claim beneficial use, then they need to tell us what equipment, what the Btu rating of that equipment is, and how they're going to determine the volume -- whether it's through manufacturers' testing information or whether it will be by meter of the gas.

Currently, Order 3 has a requirement for a self-inspection and site security plans. We are proposing to remove both of those from consideration. With all the additional detail that operators would be required to maintain that would, in fact, negate the need for having that. It would have accomplished that in its place.

We are also asking for specific comments on whether or not a 10 percent rate of return for low volume wells is adequate, too high, too low, et cetera. We are interested in getting specifically everybody's opinions on that for off-lease measurement and commingling.

Also, we are looking for comments on the time frames and the thresholds that we have proposed for submitting applications for facility measurement points.

Questions, comments, involving site security?

MR. TOM SHIPPS: I've got a number of them. My name is Tom Shipps. I serve as general counsel for the Southern Ute Indian Tribe, which is kind of in a unique position here because the Tribe serves as its own operating company that's very active on the reservation, but it also serves as a governmental compliance arm in monitoring the compliance of lessees and operators with respect to existing oil and gas leases.

Just as a preliminary matter, you know, it seems to me kind of odd, looking around the room and seeing how many people have white hair that they're talking about how old those regulations were that were passed in the 1980s. Some of us, even Terry Knight who was here -- has Terry left? We certainly will remember those periods.

In any event, with regard to measurement, commingling, I'm curious about why is it important to get the comments that you have requested with respect to the

10 percent rate of return with regard to low volume production? And, also, would you explain in some more detail the process that you anticipate with respect to the obtaining of the Federal Measurement Point and the time periods for that and the anticipated cost that you contemplate of that affecting industry? You know, there's some -- there are a couple questions in that, in itself, that we need to have answered.

As a preliminary matter, I would also want to say that looking at all three of these different subparts that are being proposed, it's obvious there's been a great deal of time and energy spent by the Bureau of Land Management on addressing these issues, and I think that for those of us who have been active in this area for a long time on behalf of Tribes, we appreciate the attention that's been applied to addressing the matters.

As in previous activities, though, if the Bureau of Land Management -- and perhaps you can correct us in this regard -- but this is another example, I think, of kind of late consultation with Tribes in the process.

We appreciate the consultation we're getting, but I don't think the Tribes have been actively involved in this process now as we reach those late stages. And that doesn't necessarily go to your proposed subpart, but just as a general matter, and we've got some specific questions.

I certainly have some specific questions related to how the process you have undertaken has taken into account, for example, definitions of how royalty is computed under the Indian Mineral Development Act that might be different from what you perceive to be the formula for developing royalty or for how royalty is computed in terms of volume, value, heating, quality -- you know, whether or not there are any differences that have been evaluated and investigated by BLM in making these Rules to see if there aren't any IMDA agreements out there that have a different mechanism for computing royalty and what the relationship of that computation methodology is going to be with respect to these Rules.

So a number of comments and perhaps, you know, we can get into that discussion in more detail as we go through the different subparts and have a broader discussion at the end, but at least with respect to a couple of those measures, you know, why it's important on 10 percent rate of return and also with respect to the process for FMPs, I would appreciate your comments on that at this point. Thank you.

MR. ESTABROOK: I'll address the 10 percent rate of return. That's a really good question, and we're hoping that we get data on this, I guess. So as Mike said, the commingling proposal is that we don't want commingling generally. We think it prevents us from accurately verifying the volumes and qualities that are reported to us.

There's accuracy on certainty issues when you get into commingling. There are a lot of issues that we're trying to avoid. Obviously, there are some instances where commingling is fine or warranted, and there's three circumstances under which we would allow commingling.

Circumstance 1 is if the commingling had no impact on Federal or Tribal royalty. And this would be, for example, if there's two Tribal leases. Both have the same royalty rate. Both have the same royalty distribution. So this would probably not apply to a lot of leases. And an operator wanted to commingle production from these two leases.

Well, the Tribe is going to get the same amount of royalty in that situation regardless of what the allocation method is. It doesn't matter. It doesn't matter if it's a 90/10 split between the two leases or 50/50 or 40/60. It makes no difference. The Tribe in that circumstance will get the same amount of royalty.

So in those situations where Tribal or Federal royalty is not impacted by the allocation method, we would allow that commingling to proceed.

Circumstance 2 is for low volume leases. We realize that we have a lot of low volume production. In fact, I think roughly 21 or 22 percent of our leases would qualify as low volume being less than 15 Mcf per day which is what we defined it to start off with.

So allowing commingling in those circumstances would reduce operating cost and perhaps allow those operators to continue production for longer than if they couldn't commingle.

So we have an objective test for whether or not you would qualify for this low volume exemption where you could commingle. And that objective test is a rate of return test. It's basically a prudent operator test.

So if an operator had to spend, let's say, $50,000 to put in a new tank so that they could independently measure those two leases and, yet, the continued production on -- because now -- let's say we were going to be -- we were not going to approve commingling under any circumstance.

That operator has a decision. Do I spend $50,000 to put a new tank on a lease so they both have tanks now so I can continue production, or am I better off economically just forgetting it, plugging and abandon those leases and walking away?

So, to me, a prudent operator would do an economic $50,000 -- I'll call it an investment. It's a little bit of an odd investment -- $50,000 investment in a tank. What kind of internal rate of return could I make based on that $50,000 investment, assuming that now I could continue production on for another ten years or whatever it is?

And so we have said in the proposal that that rate of return will be 10 percent. So if an operator can make more than 10 percent on that rate of return for the investment, a prudent operator would say that, "It's worth it to put that new tank in because I'll make money on it because I can continue to produce my lease for another ten years."

If that rate of return is less than 10 percent, a prudent operator would say, "Forget it. I can get 10 percent or a better rate of return putting money in other projects." So the operator would say, "I cannot continue. It's not economic for me to put this new tank in. The $50,000 will never pay for itself with the 10 percent rate of return, so my decision would be, I will just walk away from these leases."

We don't want that. We don't want you to walk away from those leases. We want that continued production. We have a lot of low volume leases that we want to see continue to produce. We want that royalty.

So if you qualify for that less than 10 percent rate of return where you would normally walk away from those leases, then we would say, "Okay. We will approve your commingling. You don't need to buy that new tank."

We want continued production. So that's what that is about. The question is, in the preamble, is that 10 percent a reasonable threshold for an operator? We have not a lot of data on that. Operators are very reluctant to share their internal rates of return with us.

So that's what we're asking. Is 10 percent reasonable? Should it be 15? Should it be 20? What should it be? If it's not 10, what should it be? And comments with data would be really helpful rather than comments saying, "Well, it's just too low."

Now, the third category -- so we have Category 1, no royalty impacts. Category 2 is low volume exemption, and Category 3 is kind of a catch-all. If there's extenuating environmental circumstances or achieving maximum ultimate recovery, which is often the case, that would be a third category under which we could approve commingling. That is different from the low volume threshold.

Does that help answer your question?

MR. TOM SHIPPS: It does, but it begs some other questions. For example, with regard to Tribes if, in fact, the granting of that commingling in the low volume lease made the difference between that particular lease being able to continue because of paying quantities determination versus not being able to continue, it might very well be that the Tribe as the owner of that mineral resource would potentially rather see those leases lapse.

It might, for example, have more confidence in its ability to manage those energy resources than it does in the poor boy operator that happens to be on those premises.

So that ends up becoming a judgment determination from the owner of the resources. And I can tell you, and I think anybody that has been active in the BLM office here over the years has seen, for example, when the Tribe has taken over some properties that otherwise would have been lost or were lost as a result of paying quantities determinations, it then went in with its own company and dramatically increased production and was able to develop coalbed methane resources, for example, when the previous operator or owner of the lease didn't even view coalbed methane as being a viable resource.

So that may end up being -- calling a judgment call with regard to the Tribal landowner, and there is a presumption, it seems to me, on the part of the BLM, that in that instance, the continuation of low volume royalties would be a more important priority than allowing those leases to lapse.

It would seem to me that that's the kind of point in your regulations where there really ought to be some kind of a confirmation or the ability of a Tribe to say, "Hey, wait a second. Before you grant that commingling with regard to that low volume, those low volume wells, if the effect of doing that would be to prolong what might otherwise be a determination or an expiration of the lease for an absence of paying quantity determination, the Tribe needs to be consulted or the Tribe needs to be able to at least have the opportunity to say, "Hey, wait a second. That's not what we want to have happen with these properties, and this is why."

MR. ESTABROOK: That's a great comment. Thank you. I'll turn it over to Mike to answer your question about the FMPs, I believe.

MR. WADE: Yes. Currently what we are proposing for the FMPs would be that the high volume, which would be approximately the upper one-third of production, would be required to submit within the first nine months after the effective date of the Order. That would be our initial proposal.

The middle third would come the following nine months, with the lower production third coming 27 months after that for a final due date for application.

Nobody's production would be shut in if they did not have that, if they had applied and were waiting for our approval. So we would not cause anybody's production to cease just because they did not have an FMP if they had applied for it timely enough or even they even had an application pending, even if it was submitted late.

For new wells, new locations, new facilities, that FMP facility requirement would be due before they could produce and sell from that lease.

So immediate for new production, new facilities, but phased in over approximately 27 months as one-third of the production for when each operator would be applying for their FMPs. That's what we are proposing.

What we would like input on is, is that an adequate time frame? Do we need to adjust that to something over nine months for the high producing? Should it be more than, less than? We made a best guess. Is it okay? Give us some more information on those items. Okay?

What was the other part of your question?

MR. TOM SHIPPS: Actually, that's helpful. I don't know if you -- I know that there are estimates in your discussions about what you think the impact is going to be on industry making those conversions.

Have you also in analyzing those impacts thought about what the difference is with respect to making the conversions on Federal or Tribal or Indian lands versus activities that are taking place on neighboring non-Indian land?

MR. WADE: Yes. The economic impact document, that is a separate document from this application. We are discussing those items. We are asking, of course, for input from industry on those numbers for facilities that already exist. All equipment is up there for an FMP. 99 percent of the time they're not going to have to make any changes, file a piece of paper saying, this is going to be the measurement point.

For example, right now, we do not have official recognition of where that point is. So in many instances, where there's a collection system of some kind, what the operator thinks is their official measurement point and where we think is the official measurement point may not be the same.

So the operator will request a specific one and say, "Here it is. It meets the specific requirements." And that's the point we want to make sure everybody is agreeing on and whether or not there's commingling, off-lease, or whatever. We want to make sure all our I's are dotted and T's are crossed.

So in 90 percent of the instances, the measurement's already there. There is nothing new for the operator to add or remove from the facilities, other than a label, a stencil on there that says, "This is the new number for this facility measurement point."

So the vast majority of times that's the impact to the operator is stenciling a new number on there, submit a new application or whatever cost may be associated with filing sundry notes and then placing the stencil out there for the identifier with the numbers on there.

Does that answer your questions on the economic side of it?

MR. TOM SHIPPS: Yeah.

MR. WADE: So there may be some instances where commingling is concerned where an operator may need to change how they're accounting for it, but in most instances, the equipment is already there. This will now be the point of measurement versus what we had originally wanted as commingling because we can't get the approval because it is not justifiable.

So as far as on-the-ground expenses, the large majority of them will have no impact, we do not believe. Operators will need to submit more data to tell us if our assumptions are incorrect in our economic analysis, and that is information we're waiting to receive from them so we can do what we need to do so we can adjust if necessary.

MR. TOM SHIPPS: I don't quit easily.

MR. WADE: That's okay.

MR. TOM SHIPPS: I appreciate that. And I don't want to detract from your time to provide other things, but I am curious about the fact that the conversion into the FMPs, which a great deal of thought obviously has gone into that, and having worked in royalty audit areas and those type of things, having an agreement as to where the measurement point is is extremely helpful and something that is really needed in many instances where there has not been clarity with regard to Federal regulations.

But I am curious, as well, with regard to both the commingling, as well as the identification of measurement point how that interfaces with, for example, Tribal severance tax laws or conditional consents that have been granted by Tribes with respect to defining where the point of measurement will be as a condition for you to be able to maintain and continue to maintain your right of way across Tribal lands.

I'm curious as to what kind of consideration you have given in developing these regulations to take into account whether this process of conversion to the FMP or your determination as to commingling or determination of Federal Measurement Points, how that is going to impact preexisting decisions that have been made by Tribal Governments or with industry that end up potentially putting them into a point of noncompliance with the condition of Tribal consent for right of way or in noncompliance with respect to a particular lease or provision.

MR. WADE: Well, that's some very good questions. Primarily, as a general rule, most measurement is required to be done prior to leaving the lease, and I believe that applies to both Federal and Indian. Okay?

If there's a separate agreement with the Tribe that sets a specific point something other than that for the measurement point, the operator will know this. Correct? So they would be submitting an application that says, "Here is the measurement point we want, and here is why. This is because we have an agreement with the Tribe for this point right here. Here's the point."

So this is -- and all we would be doing at that point would be approving a number so we can track that point. So the operators of those positions would need to tell us some of this information when they apply for their FMP numbers.

MR. TOM SHIPPS: As opposed to collecting that information from Tribes in the development of the regulation, yeah.

MR. WADE: Yeah. We have got to collect some place, and a uniform methodology would be for whoever is required to report the volume to our Office of Natural Resource Revenue would be the most logical place to begin the process.

If it reaches complications, we'll have to address those on a one-on-one basis as they occur because we know that we can't make a one-size-fits-all 100 percent of the time. So we will see instances that must be addressed individually. And when they happen, we will have to do those. Predicting which ones those are, I won't even try to guess that.

MR. TOM SHIPPS: And just as in the determination about commingling with regard to the low volume well, it seems to me if the regulation itself contains a provision with respect to the identification of a Federal Measurement Point that has an additional factor to be considered by the Bureau of Land Management, which may be compliance with preexisting Tribal law or Tribal contracts or takes into account some other important consideration by a Tribe, that might be something that would be reviewed by the Bureau in this determination of a Federal Measurement Point, that kind of safety valve -- I hate engineering terms with legal stuff -- but that kind of safety value for you, it seems to me, also provides deference to the Tribe, and it may not be something you have taken into consideration adequately as you develop this regulation -- what appears to be a wonderful solution.

We are all going to agree to a Federal Measurement Point, but I don't know -- again, that's the reason we're having these discussions whether the way you have got it right now allows for that kind of consideration, not just on a one-by-one basis, but actually puts in as an additional factor to be considered in your decision-making that kind of consultation and built-in consultation with Tribes.

MR. NEDD: Tom, you raise a very good point, so I think some of the comments we're collecting today are also food for thought, if I may use that phrase. I think that's a very good point. We look at comments especially from Tribes to finalize this Rule. Those are good points that we have to take into consideration. So I think some very good points are being raised.

MR. WADE: Anyone else? Any other comments or questions?

MS. HANNAH CARPENTER: Hannah Carpenter. I wrote down these notes about site security. I just want to know generally -- I didn't see on the slide about security. What were your increased measurements for security? Was that for operators or for -- yeah.

MR. WADE: Currently, Order 3, for example, water draining operations, would require only the recordation of the seal number on, the seal number off, and a date, and a reason -- drain water.

What we are proposing would be to include additional information as to who removed the seal, what was -- how much fluid was in the tank to begin with, how much fluid was in the tank when they finished draining the water, so that we could have additional information available. And, of course, the time as well as the date. What time of day did you run and do these drains, put the seals back on?

So that's the type of information we are looking for. The same way if they are removing the oil for hot oiling. Right now, all they would record would be the seal numbers on, seal numbers off, and the reason. Well, we're asking that they are proposing that they also record how much fluid was in the tank at the beginning, how much fluid was in the tank when they finished, and how much of that volume that they removed for hot oiling was returned to the tank so we can see the volumes because you don't to be reporting produced volumes twice.

Anything else? I think I need to pass this on to Mike McLaren.

MR. McLAREN: Hello. I'm Mike McLaren. I'm a petroleum engineer in the Pinedale field office in Wyoming. I'm going to talk a little bit about what we're proposing to change in the oil measurement regulations.

So currently, the current Order 4 has no standards for performance. It's basically a cookbook. You either manually gauge the tank or you run it through a LACT system. So what we're proposing in this 3174 is some performance standards for uncertainty based on volume, thresholds on a monthly basis.

And so if an FMP is greater than 10,000 barrels a month, we're saying that measurement process needs uncertainty plus or minus .35 percent. We got that .35 percent basically from doing an uncertainty analysis on the current order with the positive meter, positive displacement meter.

If you have an FMP that is greater than 100 barrels per month, but less than the 10,000 barrel a month threshold, we're proposing an uncertainty of plus or minus 1 percent, and that's coming from an uncertainty analysis on the manual tank gauging, and that's approximately withdrawing about 300 barrels from the tank.

Then we put in the third tier based on some suggestions of less than 100 barrels a month, plus or minus 2.5 percent, and that's basically withdrawing, say, 40 barrels out of a 400-barrel tank. A low producer is not going to be withdrawing a lot on a monthly basis.

So the current order, it references industry standards that were published in 1989. We're proposing to incorporate standards, about 21 standards, that are current API standards and two ASTM standards, which is the Table 5A and 6A.

The current Order 4 requires a pressure-vacuum thief hatch or vent line valve for tanks. We're proposing the pressure vacuum relief valve, telling where we want it and what we want it set at. We're also requiring that the tanks maintain a pressure-vacuum integrity which is not stated in your Order 4. It's insinuated because the equipment is there, but it doesn't clearly state that it's required.

The current 4 requires the tank calibration tables, but it doesn't specify the increments. We are proposing tank capacities to be reported in 1/8-inch increments, which matches the industry standard for manual tanks.

The current Order 4 gives you requirements for tank gauging and sampling, but in no specific order. It's random. What we are proposing is not only just the requirements for each process of it, but the step-by-step procedure for the manual tank gauging. It's following the current API 18.1 standard.

So current Order 4 requires two consecutive gauges within 1/4-inch. Based on the current API standard, the requirement that we're proposing is to require two identical gauges or three gauges within 1/8-inch.

The current Order 4, it allows the Lease Automatic Custody Transfer system, the LACT system. It requires an automatic temperature compensator or a temperature gravity compensator and only allows the use of a positive displacement meter.

What we're proposing is to prohibit the automatic temperature compensator and temperature gravity compensator and requiring the use of a temperature averager, and we are also allowing the Coriolis meter in lieu of positive displacement meters.

And the reason we're proposing to eliminate the automatic temperature compensator is, it adjusts the total reading automatically. There's no raw data. That totalizer has already been adjusted compensated for temperature. So in order for us to properly do an audit, we need raw data, too.

So, again, Order 4 only allows measurement by tank gauge or by a LACT system. We're proposing to have the tank gauging, the LACT system, and a Coriolis stand-alone system, the Coriolis measurement system.

What we're proposing for this Coriolis measurement system is minimum requirements of 8400 pulse per barrel resolution. Specifications for the Coriolis references accuracy, influence effects, stability, pressure drop.

We're proposing that they notify the BLM within 24 hours of changing any calibration factors, again nonresettable totalizers. Part of the approving process is to require verification of the meter zero.

The Coriolis is capable of determining a net standard volume. And we're proposing API gravity to be determined either from composite samplers that the operators choose to install or from the density reading of the Coriolis meter itself.

And we have a list of display, onsite display requirements, similar to what the gas measurement has for the gas measurement. And we have a quantity transaction record requirement, configuration log, event log, and log requirements we're proposing.

Currently Order 4 talks about their LACT proving done monthly if it's 100,000 barrels or more or quarterly, whatever comes first. What we're proposing is for the LACT or Coriolis measurement system to prove every 50,000 barrels or quarterly, whichever comes first. And the 50,000 barrels, we come up from a statistic analysis -- at what volumes does the meter factor change equal to average cost of proving, and we use the average proving cost of the $550, and we come up with the 50,000 barrels for that volume.

The current proving requirements in the Order 4 has no standards for prover sizing, no standards for proving conditions, or no standards for minimum pulses during a proving run.

So what we're proposing based on API standards are minimum and maximum prover fluid velocity, prover sizing. We are stating we want to prove at normal flow pressure and gravity, and we do state a proposal of what we consider a normal proving condition, and then we are generating a small volume prover generates less than 10,000 pulses on a proving run. We would propose to require pulse interpolation.

Currently the measurement tickets are for -- there's none for LACTs right now, and they're in the Order 3. What we are proposing in 3174 is to generate a measurement ticket after proving and monthly for LACTs and Coriolis.

And in the preamble discussion of the Rule, we are asking for data and comments on numerous items -- specifically, on the volume uncertainty levels that we propose. We are hoping to get comments with some uncertainty analysis if they don't agree with what we're proposing.

We're asking for data on the use of automatic tank gauging systems, hybrid tank measurement. We're hearing a lot of industries stating they want to use it, but at the time we were drafting the Rule, no one had come forward to us requesting a variance to use it. We had no data. We had no input on it.

We're asking for the composite sampling system on the Coriolis system. It's an expense that the operator may not want to incur. So what we're proposing is, if they're not going to take a sample, we won't allow a deduction for sediment and water. So we're asking for comments on that approach if they think it's a good one.

We're asking for ways to address the meter factor determinations if we have the variable flow rates or fluctuating pressure or different oil gravities, and we're asking for average meter factor or establish a dynamic meter factor that would automatically adjust within the computer for flowing conditions.

And then, as Rich talked about, the approach for dealing with the violations and corrective actions. That's kind of the gist what we're proposing and changing for the oil measurements.

Do we have questions or comments? I guess not, so with that, I will turn it over to Rich to talk about gas measurements.

MR. ESTABROOK: All right. Thank you.

MR. NEDD: Do we want to get a short break?

THE FACILITATOR: Do we want to take a break now?

MR. NEDD: Yes. I see some heads nodding.

(A recess was taken from 10:25 a.m. to 10:40 a.m.)

MR. ESTABROOK: Okay. We're going to start back up. The last proposed change we're going to talk about is Subpart 3175 on gas measurement.

Onshore Order 5 only addresses gas measurement by orifice points and mechanical recorders. It was written in 1989, and that's pretty much all we had in 1989 was mechanical recorders and orifice plates.

EGM systems are not addressed in Onshore Order 5; however, each State jurisdiction has a notice to lessees that addressed EGM or electronic gas measurement systems.

So for Colorado, Colorado has an NTL 20077-1, I believe, that covers electronic flow computers. New Mexico has their own version, although basically they're all identical.

Proposed 3175 would retain orifice plates as the primary type of gas measurement. It would also allow mechanical recorders -- I'll get into that a little bit more in a minute here. It would also incorporate electronic gas measurement systems and automatically approved, and it would have specific guidance for alternate measurement and flow conditioners.

And that specific guidance for alternate measurement and flow conditioners would involve the production measurement team for a national review of those devices.

Order 5, much like Order 4, is a cookbook. It has specific things you have to do, but nowhere in Order 5 are there any stated performance goals. What is it that we're trying to achieve with all these requirements? It's not stated anywhere specifically, like in Order 4.

Order 5 has three tiers of requirements, however, that I'll show a little graph in my next slide. The proposed 3175 would establish four tiers of requirements based on average flow rates. So let me go through this.

First, let's talk about the existing Onshore Order 5. So I hope this graph makes sense, but along the Y axis here is the average monthly flow in Mcf per day. So all the requirements in existing Order 5 are in effect if the average monthly flow is greater than 200 Mcf per day. If you're flowing less than 200 Mcf per day, Order 5 no longer requires continuous temperature measurement. That's this (indicating) right here.

If you're flowing under 100 Mcf a day, Order 5 no longer requires the differential pen to operate in the outer two-thirds of the chart, and the bader ratio limits, .15 to .7, you no longer have to comply with those, either.

The proposed 3175 takes this tiered concept and sort of expands on it and refines it a little bit. The proposed 3175 would have four tiers, actually, of requirements.

For meters measuring more than 1,000 Mcf per day, which we have not that many of -- less than 2 percent of our meters we estimate fall into this category -- these will be called a very high volume meter.

Meters measuring between 100 and 1,000 Mcf per day would be called a high volume meter. Meters measuring between 15 Mcf per day and 100 Mcf per day would be called low volume meters. I think that's our biggest category with around 40 percent of our meters fall into that category, and anything less than 15 Mcf would be called marginal volume. And I think around 21 percent of our meters, we estimate, fall into that category.

Now, the significance of these categories is the performance standards are unique to each category, and the individual cookbook-like requirements are unique to each category. And the idea here is that the higher the volume, the higher the risk of mismeasurement is when it comes to royalty.

And so we want very strict standards for high volume meters. One thing, a high volume meter is generating a lot of revenue or measuring a lot of revenue, and operators, we believe, can afford to comply with these strict standards and, also, the very high volume meter, as I said, if it's mismeasuring because there's so much volume going through it, there's a huge risk of royalty being incorrectly measured if the measurement is inaccurate.

If you go down the scale, high volume, low volume, marginal, we will be less and less strict the lower the volume is with our requirements. One reason is that because you're measuring less volume, a mismeasurement of an 15 Mcf a day is not going to be nearly as significant from the royalty standpoint as a mismeasurement on a 1,000 Mcf per day meter.

And, secondly, our intent here is to try to provide some economic relief to operators so that they can continue to operate these lower volume meters. So that's the intent of these categories.

So we have three uncertainty or three performance standards that we specifically are proposing in 3175. One deals with uncertainty, both for volume and heating volume. One deals with the statistically significant bias, which is a meter that you know is reading high or you know is reading low, and this third one is very critical.

It's verifiability. And that is our ability, BLM's ability, to independently verify all measurements coming from that device.

So for very high volume FMPs, facility measurement points, we are proposing that you must maintain an overall measurement uncertainty of plus or minus 2 percent for volume and overall uncertainty in average annual heating value of plus or minus 1 percent.

There would be no allowable statistically significant bias, and all measurements must be verifiable.

For high volume FMPs, the uncertainty and volume determination would be 3 percent -- plus or minus 3 percent. The uncertainty in heating value -- this is average annual heating value -- would be plus or minus 2 percent. No statistically significant bias would be allowed, and verifiability would be required.

For low volume, we would do away with the uncertainty requirements. This is very similar to the current Onshore Order 5, the intent of the current Onshore Order 5. You still could have no statistically significant bias in your meter, and verifiability would be required.

For marginal volume, we would not care about uncertainty or bias, but we still want verifiability and measurement. So, again, these are specifically stated in the proposed 3175, and if you look at the individual requirements of 3175, this thought process was used to develop what categories have to comply with different things in Order 5, in 3175.

Order 5 adopts one and only one industry standard, and that's AGA Report No. 3, also known as API 14.3 and, specifically, the 1985 edition. This covers the primary device, the orifice plate, and the flow rate calculations.

Proposed 3175 would adopt new API and GPA -- GPA is Gas Processors Association. API is American Petroleum Institute -- covering the primary device, electronic gas measurement systems, flow rate volume, and heating value calculations, flow rate, and gas sampling and analysis.

A quick example -- the 1985 version of AGA Report No. 3 has specific places where you put two bundles, which go in front of an orifice plate to help straighten the flow to have an accurate measurement. However, this standard was based on old data. New testing done in the early 1990s showed that if you actually complied with the two-bundle placement, you bias your measurement by up to 1 percent or even greater if you put it where they tell you to. You're actually getting inaccurate measurement. So we're going to adopt new APA standards that are based on better data and result in better measurements.

Current Order 5 has no inspection requirements for meter tubes. Meter tubes are a critical piece of an orifice meter. And if you -- API has numerous standards relating to meter tubes about roundness and surface roughness and other things.

And we believe that because the meter tubes do affect measurement that they should be inspected now and then, and that currently is not required by Order 5. So proposed 3175 would require meter tubes to be inspected, and the frequency of inspection would depend on the classification of meter -- this high, very high, low margin.

So for marginal volume, less than 15 Mcf per day, we would not require any meter tube inspections whatsoever.

For low volume, which is 15 to 100 Mcf per day, we are proposing a visual inspection. This would be using a device like a baroscope where you use fiber optic and look inside the tube without having to disassemble the meter tube. We are proposing that you do that once every five years.

For high volume, 100 for 1,000 Mcf per day, we are proposing a visual inspection once every two years and a detailed inspection once every ten years. A detailed inspection would be where you would go in and physically disassemble the meter tube and go in and measure the diameters and look for scale buildup and actually do a very thorough inspection. This requires shutting the meter in, removing the meter tube, and disassembling it to inspect it.

For very high volume FMPs, over 1,000 Mcf's per day, we are proposing a visual inspection once every year and a detailed inspection once every five years. Of course, if a visual inspection identified potential problems like scale buildup or damage to the meter tube, that could trigger a detailed inspection and correction of the problem.

Onshore Order 5 currently, as already stated, mechanical recorders are automatically approved. In proposed

3175, mechanical recorders would be restricted only to those meters measuring less than 100 Mcf per day.

We do not think that mechanical recorders can achieve the uncertainty requirements that we are proposing for high and very high volume FMPs.

Order 5, this is the one and only requirement related to heating value, and I'll remind you that heating value and volume affect royalty the same. They both carry the same weight.

Onshore Order 5 only requires that Btu's be determined once per year. There are no requirements in Order 5 where you take the sample, how you take the sample, how you analyze the sample, how you report the Btu's. None of that is in Order 5. We have no teeth on that right now.

The proposed 3175 would establish a sampling frequency as follows. For marginal volume FMPs, sampling frequency would basically remain the same as it is in Order 5 at once per year.

For low volume in FMPs, we would require a fixed sampling once every six months. For high volume and very high volume, we're going to change things up a little bit -- or we're proposing to.

For high volume FMPs, there would be an initial sampling frequency of once every three months, quarterly basically. But what we were proposing for high volume FMPs is that at three months, that frequency would apply for a while, or until we get, I believe, 5 samples. After that, after we have enough data to do a statistical analysis of the variability of heating volume from sample to sample, we can determine the average annual heating value uncertainty of that FMP.

And based on that uncertainty, if it didn't meet the 2 percent uncertainty, we will require or we would require, proposing to require, that that sampling frequency be kicked up to a higher frequency.

If you can achieve that 2 percent uncertainty with less frequent sampling, we would not require the three months. You might be able to drop back to six months. So we call this dynamic sample frequency. It would be dependent on the statistical variability of heating value from sample to sample.

Similarly, for very high volume FMPs, we would initially require a once per month sample and then vary that requirement in order to achieve a heating value uncertainty of plus or minus 1 percent. This may result in more frequent sampling or it may result in less frequent sampling, depending on how variable that heating value is.

So if you have a nice heating value that is consistent from month to month, we may say you can now drop that to quarterly or even six months because that heating value variability is not very high.

Just continuing on this topic, if you cannot achieve that plus or minus 1 percent or plus or minus 2 percent in heating value uncertainty by spot sampling, the variability is just all over the place, then we would require a composite or online gas chromatograph, GC, to be installed.

Another proposal is that we would require all gas samples for any FMP, regardless of the category, to be submitted to the BLM into a new database we are developing called GARVS, Gas Analysis Reporting and Verification System.

All gas analyses used for royalty determination would be input into this system, and this system would do the statistical analysis on heating value variability in order to determine what the new sampling frequency would be, at least for high and very high volume FMPs. It would be a completely automated process.

Order 5 has no requirements for sample location or method and no requirements for the gas chromatograph. The gas chromatograph is the thing that looks at that sample and figures out what components are in there and, from that, heating value and another thing called relative density are calculated.

What we're proposing is -- and this goes beyond what the Gas Processors Association and API require. We're throwing it out there. We're proposing that the sample probe be installed at a specific location downstream of an orifice plate one to two times dimension DL downstream of the primary device. Dimension DL is the minimum required pipeline downstream of an orifice plate.

The idea of this is because many of our FMPs are at wellhead locations, and even with the best separation you can get, there's a possibility of some entrained liquid in that flow. We want those molecules, heavy-end molecules, to be accounted for. We think that if you put a sampling probe where we're suggesting it should go, right down downstream of the orifice plate where with high velocity, there is a huge amount of turbulence that those liquids will be entrained in the gas and will be picked up by that sample probe, and we will be able to account for those liquids in the heating value.

This is one of the specific things that we're asking for comments and data on, actually. We would allow for spot sampling methods. Fill an empty helium pop, a floating piston method, constant pressure method, and portable gas chromatograph.

We would specify requirements for the calibration and operation of gas chromatographs, and we're also proposing that if a hexane plus analysis, C6 plus analysis, shows a mole percent greater than 0.25 percent that you would then have to send it through an extended analysis. This is one of the specific things that we're going to request data on.

There's no requirements for Btu reporting on Onshore Order 5. Proposed 3175 would establish requirements for Btu reporting. Btu's can be reported in a whole bunch of different ways.

For example, they could be reported as gross or net, real or ideal, dry, wet, or as-delivered under four different pressure bases or maybe more. Temperature is usually 60 degrees Farenheit.

So from the same sample, you could potentially get -- I don't know how to multiply that -- but you could potentially get 30 different Btu values or something like that, a big number.

Our proposal would specify what conditions we want that Btu reported under -- gross, real, dry, no water vapor, 14.73 psi, and 60 degrees Fahrenheit.

Order 5 and the State-wide notices to lessees for electronic flow computers, there are no requirements for independent testing of transducers or flow computers. All transducers or flow computers are basically just accepted.

One of the things the State-wide NTLs have is an uncertainty requirement, plus or minus 3 percent, if you're more than 100 FMP per day. And to calculate that uncertainty, the transducer's uncertainty is very critical of this. Currently our uncertainty calculator takes those manufacturer performance specifications as the truth and uses those numbers directly.

Currently, there is no independent verification of those performance specifications. We have no idea if they're really true. Manufacturers have no transparent process that we're aware of for determining those performance specifications. Most of their methods for determining transducer performance are proprietary.

What we're proposing in 3175 would be that all transducers used for high and very high volumes FMPs, including existing ones, would have to go through a set testing protocol, a transparent protocol, to find in the standard in order to determine what the performance specifications are -- actually are. And those performance specifications we would use to determine overall uncertainty.

The PMT or Production Measurement Team, would review the results of these tests and develop a list of approved devices. That list would be on a BLM website where BLM or an operator or anyone who wanted to could go and just hit a pick-down list of approved transducers, and those are all the ones that this production measurement team has reviewed and approved.

Just as a side note, we would also have the same pick list kind of feature for primary devices, flow conditioners, and I believe for Coriolis meters and oil measurement devices, as well. So there would be a single place that operators and BLM could go to find out all approved equipment used for FMPs.

Specifically, we are asking for comments and data, and you can give us comments and data on anything you want, obviously, but we're really interested in getting comments on these bullet points.

These are things typically that we're proposing that we're not all that sure of. It's kind of out there a little bit maybe, and we're really looking for input on.

So a couple things is cost to industry for type testing these transducers. We have had a hard time getting data on this. We would love to get what this actually costs. In our proposal, five transducers would have to be type tested -- five randomly selected transducers off the assembly line.

And our specific questions are, is five transducers a good representative sample? Should it be more? Should it be less?

We don't have a lot of information on gas chromatographs. There's not a lot of standards out there related to gas chromatographs, so we're looking for information, other standards, that we should be adopting or looking at to discuss gas chromatographs.

API 22.26 the testing protocol for gas

chromatographs -- it just came out. Should we be adopting that one? Should we be looking at that one, for example?

The next one is a big one. Data showing water vapor saturation. This gets back to our proposal of requiring Btu's to be reported as dry, having no water vapor saturation.

Wet water vapor, if you report Btu's as wet or saturated, that is in most cases totally unrealistic. You are deducting water vapor that cannot possibly exist at the meter. So that one, we're throwing out or proposing to throw out altogether.

The third one is called as-delivered, which is water vapor at meter pressure and temperature. However, that is still an assumption that that gas is saturated with water vapor at that meter pressure and temperature. What data is out there to verify that that's a legitimate assumption? And we're looking for that data.

Without that data, you know, we believe in our proposal that dry -- you can't justify that there's actually water vapor there, and maybe then we should report dry. We're looking for data to show that that as-delivered is a legitimate number and can be backed up with data.

I talked about this earlier. We are proposing the sample probe to be one to two times dimension DL downstream of the primary device. This is just an idea. There's no data out there on this. We would love to see some data. Does sample probe location affect the composition at all? If it does, does it -- would we be getting too rich of a sample or too lean of a sample? We would love some data on this.

Cost of retrofitting orifice meters to meet eccentricity requirements of API 14.3.2, the new eccentricity requirements have tightened in the new API standards compared to the old 1985 standard. What is this going to cost to comply with this?

One of the things is that we would propose the chart integration companies -- again, this refers to low and marginal volume FMPs. We are proposing that they would switch to the new '92 or 2013 flow rate calculations. How does that affect chart integration companies? We would like to hear from chart integration companies to see if that would impose an undue financial burden on them. Again, we are talking low volume meters here.

And, finally, data showing the difference between hexane plus and nonane plus analysis as a function of hexane plus mole percent. This gets back to our proposal of requiring extended analysis if there's more than a quarter of a mole percent of hexane plus. Is there data out there to show if you had more than 1 percent hexane plus, it doesn't make any significant difference on heating value. We would love to see that data.

And questions and comments? Also, there's some additional information here on where you can find these PowerPoints and where you can make comments on or where you can make comments to.

But with that, I'll put it up to questions on the proposed 3175.

MR. DAVIS DONAGAN: I have a couple questions. Davis Donagan, Red Ceder Gathering. A couple of questions on the updating of the meter tubes to the newer AGA. You talked about straightening them. In the past, those meters tubes that were installed back and were under the approved standards were more or less grandfathered in. Will this still be the case on the meter tubes or will they all have to be updated?

MR. ESTABROOK: Great question, and I believe our proposal is that high and very high FMP meter tubes will have to be updated. Low and marginal FMP meter tubes will not have to be updated.

Now, that doesn't necessarily mean that any changes would be required because I'm guessing that your old 1985 -- you're talking about meter tube lengths particularly?

The old 1985 standard is beta ratio dependent, and they were generally designed for the maximum beta ratio. If they're that old, my guess is that your beta ratio is tiny and probably would be just fine under the new standards. I'm just throwing that out there.

So I believe the requirement would only allow -- would only be applied to high and very high volume FMPs in the proposed Rule to retrofit those.

MR. DAVIS DONAGAN: Okay. That more or less answers the beta ratio part of the question, but I guess specifically I was talking more about the flow conditioner or the straightening vein itself.

MR. ESTABROOK: I believe, again, for high and very high volume FMPs, the straightening vein would have to comply with the new AGA standard, the latest one of the 2000 version. Okay? And that would be straightening veins.

Flow conditioners are a little different issue, but that would be straightening veins.

MR. DAVIS DONAGAN: They will still be accepted in the new --

MR. ESTABROOK: Straightening veins or two bundles will still be accepted because they're accepted in API 14.32.

MR. DAVIS DONAGAN: And will that follow the existing NTL that is out for Colorado? I know there's one for Colorado. I assume that it's similar to the rest of the United States.

MR. ESTABROOK: I can't say for sure. My thought initially is Colorado NTL would be a good starting point. That's for isolating flow conditions. Yeah.

MR. DAVIS DONAGAN: And then the other question that I had was as far as the meter tube inspection, you talked about a visual inspection. So what's the criteria for rejection because I've looked through baroscopes before and had conversations with the other persons on site looking through, and it looks like there's something in that straightening vein. I don't think so. It looks like a shadow. So what's the criteria for the reject or repair of that meter tube?

MR. ESTABROOK: That's a great question, and if you have ideas on what it should be, you should comment to that effect. I don't have a lot of baroscope experience, so it's hard for me to say what we're going to find out there. But, again, if you guys have any suggestions, we'd love to hear.

MR. DAVIS DONAGAN: And my next question is, what is the criteria for a detailed inspection? Are you actually going to measure the bore at four different spots in the meter tube? Are you actually going to measure the distance downstream of the temperature element? What's the criteria? Is that detailed anywhere or is that just thrown out? We're going to make this detailed, but we don't know really know what is detailed yet.

MR. ESTABROOK: No, that's specified. The detail inspection would be to verify all the API standards relating to meter tubes -- all the check measurements that are required, the measurements 1 inch down at the pressure taps --

the whole thing that API has standards for relating to meter tubes.

You have to do all the measurements required to verify that the meter tubes meets the API standards. So anything that would be required by API dealing with meter tubes would be required to be checked during that detailed inspection.

So, yes, miking at the different places, the roundness tolerances, making sure all the inside diameters are consistent all the way on both sides of the orifice plate.

MR. DAVIS DONAGAN: So the air standards would be the same as the AJ Construction standard as far as tolerances in the meter tubes?

MR. ESTABROOK: Yes.

MR. DAVIS DONAGAN: Okay. Well, I can see where that would cost a considerable amount of money doing on-site. You'd have to hire a meter tube manufacturer to come out and do an on-site inspection to measure those meter tubes because those tools aren't available to every measurement technician, so I can see an increased cost there.

The other thing you mentioned was sample probes, two downstream lengths downstream of the orifice place. I think that really goes against the AGA specs of having four unrestricted downstream diameters in an orifice meter situation. So I think I would be real careful as to -- you need to stay within what the AGA has already proven acceptable.

MR. ESTABROOK: Okay.

MR. DAVIS DONAGAN: I don't know where that came from. Was that some scientist that --

MR. ESTABROOK: I wish I could say it was that technical. It was based on discussions that we have had with industry, with people that know far more about gas sampling than I do. There's been studies that show not necessarily with orifice plates, but different types of devices.

And I haven't seen the study, but I've heard it discussed at API meetings where if you sample downstream, far downstream of the primary device, you get, let's say, about 1,000 Btu's.

If you move that sample point up closer to the primary device, it jumps dramatically, so the question is which is right. Also realize that -- and, again, we would love to get comments on this because we're throwing it out there.

Also realize that the API and GPA standards are based on clean, dry gas with no liquids entrained at all, so I think the standard of, I think it is, 5 diameters down of a major disturbance like an orifice plate in the GPA and API standards are based on no liquids, but that is not reality for lease level measurement. So that's kind of the difference that I see.

MR. DAVIS DONAGAN: Okay.

MR. ESTABROOK: Okay?

MR. DAVIS DONAGAN: Okay. I agree with that. Throw wet gas into a meter tube, you affect accuracy.

MR. ESTABROOK: Yes.

MR. DAVIS DONAGAN: Which brings us to the last question I had which was basically on the wet-dry gas measurement issue. For coal gas, which is primarily what we measure here in the San Juan Basin, it's seldom that the producer can deliver that gas dry at the wellhead, which as a gathering company, Red Cedar Gathering, that's the only possible way I can give dry credit to a producer for gas being delivered onto our system.

MR. ESTABROOK: Okay.

MR. DAVIS DONAGAN: Does that make sense?

MR. ESTABROOK: I think it does, but I want to make sure that we're talking the same terminology. I think we are, but I just want to make sure.

When we're talking dry, we're talking strictly of water vapor. We're not talking about entrained hydrocarbon liquids?

MR. DAVIS DONAGAN: Yes. Physically dry gas is 7 pounds or less per million cubic feet of water.

MR. ESTABROOK: And I've heard plenty of

analogies -- or not analogies, but anecdotes. We know that there's liquid water at especially coalbed wells, and so clearly -- the story goes that clearly, that is saturated with water, water vapor because liquid water is starting to form, so it has to be saturated.

But the data that I have seen, and there is some data from the Powder River Basin that one company has been willing to share with me, and they did an extensive study on water vapor using chilled mirror devices and actually measuring -- this is coalbed, by the way -- and their data shows, preliminary data shows pretty clearly that that assumption of saturation is not very good, and it seems to be temperature dependent.

For example, when it's nighttime and it's cold, you might be saturated with water vapor. When it's hot out and warmer, you're no longer saturated with water vapor.

So our question is -- and, again, we're looking for data on this. Our question is, why should we take the hit on 100 percent water vapor deduction when it's probably not a 100 percent saturated all the time?

We realize that the dry assumption is sort of biasing the other way because there probably is water vapor there, but we're looking for some data to base something else on.

Without that data, it's really hard for us to say, we'll let you continue deducting from royalties basically for water vapor that may or may not be there. So we're looking for data.

MR. DAVIS DONAGAN: I agree.

MR. ESTABROOK: Okay.

MR. DAVIS DONAGAN: The problem with dew point is that it is temperature related.

MR. ESTABROOK: It is.

MR. DAVIS DONAGAN: And the only real way that you can do that separation is at pressure, at temperature with a constant temperature being fed into a flow computer and constant pressure. As that pressure and temperature changes, so does your dew point.

MR. ESTABROOK: But that flow computer still assumes that it's doing that water vapor calculation with the assumption it's 100 percent saturated at all times, at whatever meter pressure and temperature it is, and I don't agree with that assumption that the gas is always saturated with water vapor at meter pressure and temperature. And I would like to see data to show that it is or what is it, really?

MR. DAVIS DONAGAN: I don't agree with the statement you made about the flow computer because the flow computer is doing exactly what you tell it to do.

MR. ESTABROOK: Right.

MR. DAVIS DONAGAN: It's not compensating for moisture in any way -- not even in specific gravity because that's determined through the gas sample, and it is dry.

MR. ESTABROOK: Many flow computers -- as you know, many flow computers do have a water vapor factor that you can turn on which starts calculating the saturated amount, put --

MR. DAVIS DONAGAN: And to input that, you have to have some kind of instrument that's feeding that data, correct? And that's the other part of the problem.

It's unrealistic, I think, for the BLM to expect us to do an actual measurement of dew point. It's impossible to do it. We just don't have the technology to do it. On wet gas coal wells, it's almost impossible to get a regulator to work in 6 degree weather like we had this morning --

MR. ESTABROOK: I agree.

MR. DAVIS DONAGAN: -- let alone a dew point. It's just not economically feasible, either. It would be like spending $40,000 on a chromatograph. It's just not going to happen.

MR. ESTABROOK: I agree. What we're looking for -- we're not necessarily saying you have to have a chilled mirror device on every well. What we're saying is, if you can collect a database of actual chilled mirror numbers, maybe there's a way we can apply that, the findings from that study, across the board. Yeah, we're not suggesting that you have to have a chilled mirror device or a laser device, whatever, at each well.

We realize for the volume of wells that we're talking, that would be uneconomic. What we're asking for is data to justify another reporting basis, other than dry.

MR. DAVIS DONAGAN: So as far as the regulations, are we at a point in the comment period that we have enough time to make changes in that or do all that research or experimentation? How will you apply whatever information comes from now, five years from now to then -- to that BLM requirement?

MR. ESTABROOK: Well, we need that information by the December 14. Once we get that information, we'll figure out what to do with it. That will be the deliberation process.

Now, some companies have been doing this for a long time and have that information. Yeah -- go ahead.

MR. NEDD: So for the public, we need information by December 14. For the Tribes, they can submit comment until the final Rule. For Tribal entities, they can submit information beyond the December 14, but it needs to come from a Tribal entity. That's the only parenthetical.

So even though we may get comments by December 14 to begin our analysis, as new information comes in until we publish a Rule, from the Tribes, we will take that into consideration -- just a parenthetical.

MR. ESTABROOK: Thank you for that clarification. Good point.

MR. DAVIS DONAGAN: It would have been nice three years ago if we would have been included on this project to come up with this information. No one ever said a word to us, although the BLM doesn't directly correspond or communicate with gathering systems, but anyway. And I think that's all the questions I have.

MR. ESTABROOK: Okay. Thank you. Great questions.

MR. TOM SHIPPS: Just to follow up on the Red Cedar comments, and I know that you guys have difficult jobs, but you've got to keep in mind, too, with regard to the Tribe, the Tribe is the majority owner for the gatherer. We have got our own oil and gas company. We have the Tribe, the Government.

And this issue about water saturation and measurement has come up not just in the context of this proposed Rule, but in the context of application of the Tribe's severance tax and also comes up in the context of what do you do with respect to industry norms and contracts based upon measurement for contract purposes for providing services and contrasting that with what may be reporting requirements in terms of, you know, heating value with regard to, is this a value or a volume issue? Both.

So anyway, this has been a very difficult issue with regard to the water saturation, and I don't know if we can get more guidance. It does sound as if what you want to have happen ideally is some kind of -- some level of accuracy as to how much saturation there is in your gas stream, and you have suggested the way to do that is to collect a number of data points in the system in the field that then could be submitted as a base of supporting a determination that the gas is either saturated or to be able to make a realistic assumption that there is this percentage of saturation with regard to what is going on with coalbed methane gas in the field.

And along those lines, I'm wondering if this isn't an area with respect to Tribal activity where the Tribe couldn't itself be able to make a request for a variance based upon the data that it collects, and it may be -- there may not be many Tribes that are similarly positioned with regard to Southern Ute, but it seems to me that this would be another place where you might be able to give some deference to Tribal decision-making, and it may be taking into account -- the Tribe may be taking into account not just the impact on royalty, but also the impact on severance tax administration, contractual relationships with related companies, and that type of thing.

Mr. ESTABROOK: Thank you. Any other questions or comments relating to 3175? Okay. Hearing none, Mike, I'll let you close.

MR. NEDD: Again, thank you all for being out here, and I know a couple of times we talked about -- had the BLM start earlier. And we have over 200 Tribes that we interact with, and so in 2011, we began that process.

And the reason we're out here today is part of that ongoing process to gather information, and we will continue to solicit your input. It is very valuable to us to hear from you. There has been some good exchange this morning, and I believe if you have any additional information or data that you can submit beyond the December 14, continued on, we would really, really appreciate that.

I want to reiterate what Lonny said this morning. There's some one-on-one consultation that is needed. Please work with the Colorado office or you can get ahold of us certainly in DC, but the BLM Colorado office or local field office, and we will do our best to meet that need. But this is an ongoing dialog.

And I want to say what we have is a proposed Rule, and based on your input and based on our input, the final Rule will then be developed. So it's critical, absolutely critical -- and I want to say to Mr. Davis -- you said Davis. I don't know if your name is Davis, but it's never too late to give us information.

And, Tom, it's never too late to give us information. So we appreciate it again. I want to thank the entire BLM staff for putting this on here. They have this road show that they are continuing to travel, and I certainly want to thank our recorder and our facilitator and thank everyone. And this has been real good and very informative to us, and we appreciate, again, you venturing out here again whether you had to drive, fly, or whatever. So, thanks again, everyone.

THE FACILITATOR: Do you want to mention that this afternoon, there's an open forum?

MR. NEDD: Yes, I'm sorry. Yes. This afternoon from 1:00 to 4:00 is a public forum, and you are certainly welcome to come to that. It's going to be right here in this hotel, right here in this room. So same place, same time. If you want to get a second round of it, and you want to get your comments on the record twice -- no, only kidding. So come on back again. Thanks.

(Morning Session concluded.)

REPORTER'S CERTIFICATE

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I, Susan VanDenBerg, Registered Professional Reporter, Certified Court Reporter, and Notary Public, State of Colorado, do hereby certify that the said proceedings were taken in machine shorthand by me at the time and place aforesaid and were thereafter reduced to typewritten form by computer-aided transcription; that the foregoing is a true and correct transcript of my stenotype notes thereof to the best of my ability.

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